ARTHUR ANDERSEN

Tax Services

Guide to upstream oil and gas taxation in the UK

This publication is correct to the best of our knowledge and belief at the time of going to press. It is, however, written as a general guide, so it is recommended that specific professional advice is sought before any action is taken.
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Background to the UK oil industry

Exploration and production by the oil industry in the UK and on the UK continental shelf (UKCS) is regulated through a licensing system, which is managed by the Oil and Gas Directorate of the Department of Trade and Industry. By the year 2000 there were 116 oil fields, 82 gas fields and 11 condensate fields offshore in the UK sector, which at that date had produced a total of 22.7 billion barrels of oil and 1.9 trillion cubic metres of gas.

The international industry set out in the mid-sixties to find gas in the southern basin of the sector, and many large gas fields were discovered and started production before the end of the decade. In the early seventies a number of world-class oilfields were discovered, with first oil being achieved in 1975. The UK achieved self-sufficiency early in the next decade at over 1.8 million barrels per day. The following twenty years has seen daily average production at over two million barrels with an anticipated peak of some three million barrels. The production profile of the UKCS is shown in Figure 1 below.

The quest for the industry in the 1980s was to explore the more remote parts of the UKCS, which involved moves into the deeper waters and harsher weather conditions of the North Atlantic. At the same time, many more major oil and gas fields were found in the now mature North Sea sector and the Irish Sea. The industry continued to build major infrastructure in the form of export pipelines linking the major terminals with the majority of the producing fields.

The nineties saw a change in the industry with many initiatives to reduce costs to extend the life of facilities as the threat of abandonment loomed for a number of fields. The processing of third party hydrocarbons via tie-backs of satellite fields to existing platforms became increasingly important as a result.

The second half of the decade saw even greater changes both in the North Sea and globally. A number of corporate mergers were announced between some of the world's leading players: BP acquired both Amoco and Arco, whilst Total merged with Fina and Elf. The biggest merger was between Exxon and Mobil forming the world's largest oil company. Other deals involved Spanish state-owned Repsol acquiring the Argentinean major YPF; while closer to home Monument was acquired by another UK independent (Lasmo), and Hardy Oil and Gas merged with British Borneo, the combined company being subsequently acquired by Agip. In Norway Norsk Hydro acquired the other non-state owned Norwegian oil company (Saga), and sold its UK assets to US-based Conoco in June 2000.

In the North Sea a large number of fields changed hands with some companies able to extend field life and production by reducing costs. Although as a result of this a number of the major players have reduced their interests in the region, at the end of 1999 the league tables for acreage held, production, and remaining reserves were still dominated by the world's larger oil companies.

As the industry moves into the 21st century what are the key drivers that will shape the industry over the coming years, and what effect will this have on the North Sea?

We believe that there will be a continued decline in the number of assets held by the majors as non-core assets are divested after the mega mergers of the previous few years. More mature fields will be operated by smaller, leaner companies and the formation of new start-up companies will continue as UKCS reserves become harder to find and less economically attractive for the global majors. The continued advancement of technology will also assist prolonged field life and drive down costs further.

Accordingly, the UK sector of the North Sea should remain attractive to companies wishing to establish a production base in the current environment of low government take and political stability, although clearly this could be materially affected by future fiscal changes, either to raise tax take from the North Sea or to introduce tax incentives. Details of the most recent North Sea fiscal review and the outcome are provided on page 8.

Figure 1: UKCS production profile

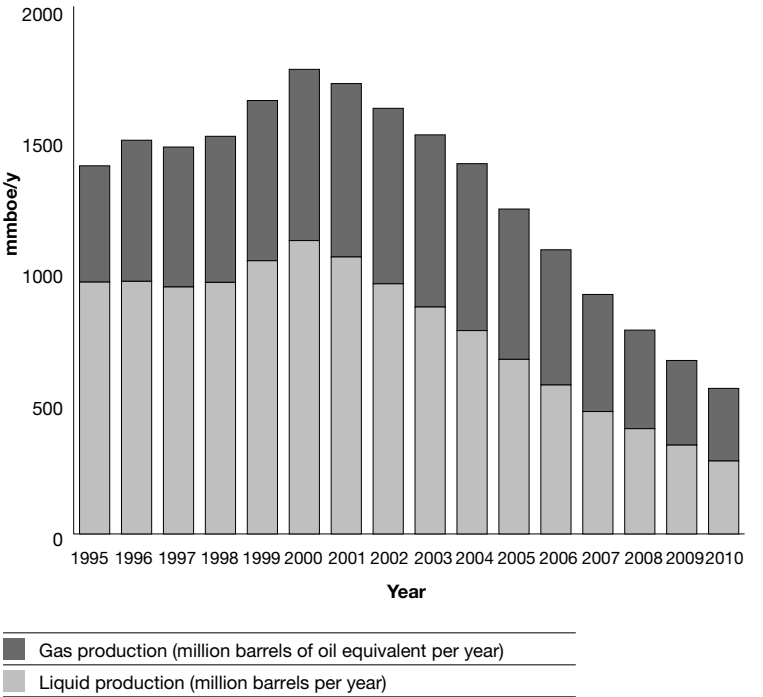


Figure 2: UK continental shelf licensed acreage

The diagram shows licensed areas in the UKCS as at September 2000. The next licensing round is expected to be announced in late 2000.

Licensing terms

History of licensing legislation
Throughout the last century several acts helped to shape the legislative framework for oil and gas licensing in the UK. The following however have had particular significance:

Petroleum (Production) Act 1934: this Act established the national ownership of all petroleum (oil and natural gas) resources existing in natural conditions in strata in Great Britain and endowed the government with the power to grant licences for its exploration and development. This act also established the government's authority to regulate the application for and issuing of licences, their content, and fees.

Continental Shelf Act 1964: the *Geneva Convention on the Law of the Sea (1958)* established the sovereign right of countries to undertake exploration and production of the natural resources of their continental shelves to a distance of 200 miles from shore. By 1965 Norway, Denmark, West Germany, the UK and the Netherlands had come to an agreement on the designation of median lines in the North Sea. The 1964 act divided the UK Continental Shelf (UKCS) into quadrants and blocks and enabled the First UK Offshore Licensing Round in 1964. Each quadrant is 1° of longitude by 1° of latitude and is divided into 30 blocks. Onshore licence areas are based on the Ordnance survey 10km x 10km grid. The most recent boundary agreement to be made is that between the UK and the Faroe Islands, which was reached in May 1999. Both countries may now allow their acreage in the 'White Zone' to be made available for licensing.

Petroleum and Submarine Pipelines Act 1975: this Act saw the establishment of the British National Oil Company (BNOC). The BNOC acquired the licence interests formerly held by the National Coal Board in the North Sea, with the right to a 51% holding, giving a state organisation a role in the safeguarding of the nation's interest in offshore resources for the first time. This role was effectively removed in 1982 however, when BNOC's holdings were transferred to Britoil Plc, with shares sold to the public in 1982 and 1985.

Oil Taxation Act 1975: this Act saw the introduction of petroleum revenue tax (PRT). PRT is a tax on profits related to separate geological and technically determined fields. This is charged at six-monthly intervals on the difference between income and expenditure. In 1993 the rate of PRT was reduced from 75% to 50%, and the tax was subsequently abolished for fields which received approval on or after 16 March 1993.

Petroleum Act 1998: this Act consolidates legislation covered by the three acts above, and covers a range of legal issues relating to all stages of upstream exploration and production.

The UK distinguishes between onshore and offshore areas in its licensing policy, and terms and conditions vary accordingly. So far there have been 18 offshore rounds completed, with the ninth round of onshore licensing currently under way. The Department of Trade and Industry's (DTI) Oil and Gas Directorate administers the UK licensing regime. When applying for licences (seaward or landward), all applicants are judged on a range of criteria including financial capability, technical expertise, geological rationale and environmental strategy.

Offshore licensing
There are two types of offshore licence:

Exploration licence
These are non-exclusive and allow the licensee to acquire seismic, magnetic and other data over any part of the UK not covered by a production licence. In addition holders are allowed to conduct shallow drilling (of less than 350m in depth). These licences may be applied for at any time and are initially valid for three years. The initial term may be extended for a further three years at the discretion of the Secretary of State. An application fee and annual rental are charged.

Production licence
These grant exclusive exploration rights to the licensee in respect of a designated area. These licences are generally awarded during licensing rounds, although following low oil prices in the early nineties the government introduced out-of-round awards to facilitate early development of fields. Such out-of-round awards occur only occasionally, however.

Application for production licences is by open invitation, with licensing rounds occurring approximately every two years. The 19th licensing round is anticipated in late 2000, and is expected to cover acreage in the 'White Zone' between the UK and Faroe Islands. Terms and conditions of awards vary: for example, licences granted during the 18th round have an initial term of six years (after which time licensees are required to relinquish 50% of the licensed area), with a second term of 12 years (extendable by a further 18 years subject to DTI field development approval). All licences are subject to an application fee, initial rental payment and subsequent rental on an escalating scale depending on the round in which the licence was awarded.

Onshore licensing
In 1995 the *Petroleum (Production) (Landward Areas) Regulations Act* was passed. This simplified the onshore licensing system so that one licence, the petroleum exploration and development licence (PEDL) covered the majority of processes involved in petroleum exploration and development. The PEDL has broadly the same terms and conditions as the offshore production licence.

There are two other onshore licences currently issued in the UK: the supplementary seismic survey licence (SSSL) allows the holder to

extend a seismic survey into unlicensed acreage, while the methane drainage licence (MDL) relates to coal mining, allowing operators to release natural gas in the course of normal operations.

Five older types of licence are still valid but not issued. These are: the mining licence (ML), the production licence (PL), the exploration licence (EXL), the appraisal licence (AL) and the development licence (DL).

Joint operating agreements (JOAs)
The majority of licences in the UK are held by consortia. To safeguard against major disagreements in policy by members subsequent to the award, JOAs are signed covering the terms and conditions agreed by members, and approved by the DTI. Such agreements are typically standardised documents covering issues such as licence operators, budgets and voting procedure.

Unitisation
Discovery of a field covered by more than one block may be subject to exploration by competing consortia. Regulations exist allowing the unitisation of oil and gas fields to avoid competitive drilling, with parties asked to agree on respective reserves in each field and submit a proposal to the DTI unitising the field between the different blocks. However, as the major companies withdraw from the UKCS and licensing rounds increasingly cover smaller and specific areas, this is not an issue which arises frequently, particularly in view of open door policy for new acreage and out of round awards.

Taxation

Introduction

The UK currently offers one of the lowest overall tax rates for the oil and gas industry of all the major oil producing economies. The fiscal regime for the industry has remained largely unchanged since 1993 and (apart from the 1998 review) there has been reasonable stability in the context of long-term planning for investment. However previous oil price variations have affected government attitudes to the fiscal regime and could do so again in the future.

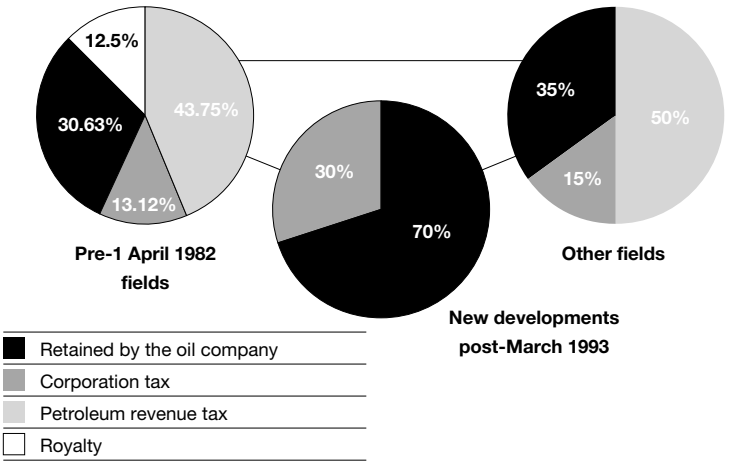
Government revenues from UK Continental Shelf (UKCS) oil and gas production are made up of payments of royalty, petroleum revenue tax (PRT) and corporation tax (CT). For fields given development consent after March 1993, royalty and PRT are not applicable, the only relevant tax being corporation tax.

Royalty is a charge on the value of oil and gas won. It is not payable where development consent was given after 1 April 1982, except for onshore fields and fields in the Southern Basin. Royalty is chargeable for these fields if development consent was given before 1 July 1988.

PRT is a tax with rules specifically reflecting the particular nature of the oil industry and is essentially a windfall tax on the profits from winning oil and gas income in the UK or UKCS. It is only applicable however to fields which were given development consent before March 1993.

Corporation tax is the main tax on business profits in the UK, but there are additional constraining rules for UKCS income. Figure 3 below gives a comparison between the current marginal government take on taxable fields with or without royalty, and for non-PRT paying fields.

Figure 3: Current marginal government take on taxable fields



Recent changes

This section highlights a number of important tax developments since 1996. Some of these relate specifically to the oil tax regime, whilst others are of a more general nature, but nonetheless significantly affect the oil and gas industry.

1997/1998 North Sea fiscal review

In the July 1997 Budget the Chancellor of the Exchequer announced a review of the North Sea fiscal regime. The government's stated aim was to ensure that "an appropriate share of profits is taxed while continuing to maintain a high level of oil industry interest in the future development of the UK's oil and gas reserves".

In his 1998 Budget the Chancellor announced a planned consultative document and outlined two possible packages for structural reform to North Sea taxation. One option envisaged a supplementary CT charge on existing ring-fence income, with no deduction for financing costs. The second option proposed an extension of PRT to all fields, including those given development consent after 15 March 1993. In addition, under this second option, it was proposed to halve oil allowance and to introduce a new PRT relief for abortive exploration expenditure. Another proposal under both options was the abolition of royalty in order to encourage companies to exploit more fully the reserves of older fields.

However on 7 September 1998, after wide industry lobbying and representations, the Chancellor of the Exchequer announced that "at the current low level of oil prices it would not be right at this stage to proceed with reform of the regime". Since that date oil prices have risen again from a low of around $10 per barrel at the beginning of 1999 to more than $30 per barrel in August 2000 with no indication of a return to the proposed reform package.

Corporation tax

Legislation contained in the *Finance Act 1997* removed the 100% trading deduction for what was known as *New Brunswick* expenditure on intangible drilling costs of second and subsequent development wells. Relief for such expenditure is now given under the mineral extraction allowances (MEA) code on a 25% reducing balance basis.

The *Finance Act 1999* repeals earlier legislation that excluded the acquisition or disposal of UK oil licences from eligibility for rollover relief on capital gains. As from 1 July 1999 oil licences are qualifying assets for the purposes of rollover relief, so that the tax can be deferred if proceeds are reinvested.

From 7 August 2000, the existing capital allowances provisions in respect of the demolition of oil installations have been extended to include the costs of preparing these facilities for reuse.

The *Finance Act 1997* introduced legislation for certain expenditure on plant and machinery with an expected working life of more than

25 years. Such assets are now pooled separately in a long life asset pool, on which writing down allowances are reduced from 25% to 6%.

With effect from 6 April 1999, dividends from UK companies do not attract the additional payment of advance corporation tax (ACT). The related tax credits attached to the dividend have been reduced so that non-resident corporate shareholders derive almost no benefit from the repayment of such credits.

For accounting periods ending on or after 1 July 1999 the corporate taxation system changes from 'pay and file' to corporation tax self assessment (CTSA). CTSA is a system requiring companies to calculate and report their tax liability. Other new procedures include an instalment payment system in respect of large companies' tax liabilities and new statutory record keeping requirements.

Petroleum revenue tax (PRT)
There have been few changes to the PRT regime since 1996. Where there have been changes these have mainly been of an administrative or anti-avoidance nature.

The *Finance Act 1999* introduced legislation relaxing the timetable for the delivery of some PRT returns. For chargeable periods ending on or after 30 June 1999 companies can apply to the Inland Revenue to defer delivery of both the participator's returns and/or the responsible person's return. Returns can be deferred indefinitely where a field is never expected to be PRT paying or for a specific period approved by the Inland Revenue provided that no PRT is expected to be payable in that period.

Prior to 21 March 2000, in periods in which the operation of safeguard relief reduced the PRT liability to such an extent that the company would get a reduced benefit from claiming expenditure which it had incurred in the period, it was common for companies to defer the claim for this expenditure in order to realise the full benefit in the future. Provisions in the *Finance Act 2000* disallow any expenditure to the extent that the claim for operating expenditure has been deferred to a later period and to the extent that this deferral reduces the participator's overall liability to tax. The tax benefits of deferring claims for capital expenditure remain.

Royalty payments

In order to produce oil and gas offshore, a licence is required from the UK government. Fees are payable to acquire licences and, amongst other conditions, on certain fields there is an obligation to pay a royalty.

Royalty is deductible in computing petroleum revenue tax (PRT) and corporation tax (CT) liabilities.

First to fourth round licences
Royalty is payable at 12.5% on the 'value of the petroleum', calculated by taking the landed value of production and deducting from it an allowance for certain costs of conveying and initial treatment.

Fifth and later round licences
Royalty is payable at 12.5% of the 'value of the petroleum', calculated as the PRT value of production, with no allowance for conveying and initial treatment.

New fields
No royalty is payable if the field qualifies as a 'new field', *ie* development consent (or approval of a development programme) was first given after 1 April 1982. Before 1 July 1988, royalty was payable if the 'new' field was in the Southern Basin or onshore.

Petroleum revenue tax (PRT)

Principles of PRT
PRT applies only to fields where development consent (or approval of a development programme) was first given before 16 March 1993 (taxable fields). It is therefore only of historic interest except for the 75 PRT paying fields within the regime, which are still material to the UKCS.

The broad outline of PRT was established in the *Oil Taxation Act 1975*. It is essentially a windfall tax on the profits from winning oil and gas under a UK licence. Each field is treated as a separate taxable unit. PRT also differs from corporation tax in that there is no capital/revenue distinction. As such, fields generally do not become PRT paying until 'payback' is reached.

Since 1993 the rate of PRT has been 50%. Profits are taxed for six-month chargeable periods to 30 June and 31 December, irrespective of the licensee's accounting date. PRT is deductible from corporation tax. PRT repaid as a result of a loss carryback is charged to corporation tax in the accounting period in which the PRT loss period ends.

Full front-end relief is given for most expenditure, after it has been claimed and allowed by the Inland Revenue. No relief is available for interest: instead, certain capital costs incurred prior to payback attract 'uplifted' relief. Relief for marginal fields is granted by means of a production allowance (oil allowance) and, for a restricted period, there is a limit (safeguard) on the amount of tax payable.

Figure 4 (page 16) sets out a sample PRT computation. The items to be entered are discussed below.

Gross profit
Gross profit represents the value of the participator's share of production from a taxable field in the chargeable period, *ie*

- Arm's length sales.
- Other sales valued by reference to special rules designed to reflect market prices.
- Appropriations.
- Stock adjustments.

It excludes:

- Royalty-in-kind.
- Oil used for production purposes.
- Certain gas sold under pre-1975 contracts.

In circumstances other than where a participator is covered by the exemption provisions, any disposal may be subject to the special valuation rules (including a possible penalty uplift), unless nominated to the Oil Taxation Office (OTO) at the time the disposal arrangements are made.

Tariff receipts
Tariff receipts (for example from shared pipelines) accruing to taxable fields are chargeable to PRT insofar as they relate to the use of a qualifying asset or related facilities.

Qualifying assets are those which have attracted actual or deemed PRT relief, with the exception of mobile assets which are not dedicated to a particular field.

Tariff receipts in respect of extraction, transportation, initial treatment or initial storage of oil attract a throughput allowance, provided they are paid by a taxable field. The participators in the owner field share an allowance equivalent to 250,000 tonnes of throughput per chargeable period for each taxable field. Unlike oil allowance there is no cumulative limit on the relief available.

The allowance cannot exceed the taxable tariff and, therefore, cannot create a loss.

Asset disposals
Receipts from disposals of a limited range of qualifying assets by taxable fields after 30 June 1982 (including, for example, insurance, compensation and receipts from the re-determination of a transmedian field) are subject to PRT.

Such receipts exclude:
- Consideration received in respect of assets disposed of more than two years after they cease to be used, or cease to give rise to tariff receipts, whichever is the later.
- Receipts on the transfer of an interest in an oil field or for oil rights.
- The excess over the original cost of the proceeds of disposal of an asset to a related participator.

Expenditure relief
Field expenditure must be claimed for the chargeable period in which it is incurred and is not deductible until it is allowed by the Inland Revenue. For these purposes expenditure is generally deemed to be incurred on the date on which the obligation to pay becomes unconditional.

To compensate for the fact that interest expense is not an allowable deduction for PRT purposes, a supplementary allowance (uplift) is given at 35% on certain (broadly capital) expenditure, notably that incurred on bringing the field into production. Uplift applies only to qualifying expenditure incurred prior to payback, as specifically defined.

The main non-deductible items are:
- Finance costs, *eg* interest.
- The cost of acquiring land or interests in land.
- Certain buildings, *eg* administrative offices.
- Deballasting.
- Expenditure that depends on the results of a field.
- Certain payments to obtain interests in oil.

Full front-end relief is given for most long-term assets with no restriction for shared assets. Long-term assets are those whose useful life could exceed the first claim period (*eg* production platforms). Expenditure incurred partly on a taxable field and partly on a non-taxable field must be apportioned.

Relief for expenditure incurred after 30 June 1982 on mobile assets not dedicated to a particular field (*eg* drilling rigs) is given over their expected useful life.

Detailed rules deal with the costs of field abandonment. Such costs are allowable for PRT if incurred for the removal or restoration of an asset or for obtaining an abandonment guarantee. Certain costs incurred in respect of defaults by a fellow participator are also allowable. Effective relief for abandonment costs may depend on the ability to set off losses against profits of earlier periods, or against other fields. Where repayments arise following a carryback, the amount of interest on tax repaid is restricted.

Generally expenditure is only allowed for a field if it relates to that field. However, the following expenditure not related to the field is deductible against a PRT paying field:
- Exploration and appraisal expenditure incurred after 15 March 1983 and before 16 March 1993, or which qualifies for transitional relief.
- Cross-field allowance for qualifying expenditure.
- Research expenditure.
- Losses from abandoned fields, subject to certain restrictions.
- Abortive exploration expenditure incurred before 16 March 1983.

Exploration and appraisal expenditure (now abolished)
Between 15 March 1983 and 16 March 1993 a participator could claim PRT relief for certain exploration or appraisal costs against any 'contemporary' taxable field interest. This relief was not available if the costs related to a PRT field, for part or all of which development consent had been given at the time the expenditure was incurred.

The allowable costs were those:
- Incurred between 15 March 1983 and 16 March 1993.
- Incurred before 16 March 1995, which were committed before 16 March 1993 (with detailed rules to define commitment in this context).
- Incurred before 31 December 1994 on a licence held on 16 March 1993, up to £10 million in total.

Relief does not depend on the expenditure being abortive, but the cost of acquiring a licence interest from the Department of Trade & Industry (DTI) is only allowed when the licence (or relevant part of it) is relinquished. There is no time limit for claiming the relief, and thus old expenditure may still qualify, although this relief may have largely been exhausted.

Cross-field allowance
There is an element of immediate relief for field development costs where a participator in a new taxable development has (or expects to have) PRT profits in another taxable field. The relief known as cross-field allowance is available for offshore taxable fields (other than those in the Southern Basin) for which development consent was first given after 16 March 1987.

The participator may elect to set off up to 10% of qualifying expenditure (incurred after 16 March 1987) against PRT profits in another field.

The definition of qualifying expenditure is linked to qualification for 'uplift' so that, for example, expenditure on leased production facilities may not qualify. Relief actually claimed under these rules will not however attract uplift.

The relief will only provide a benefit to those companies which have or will have a PRT liability against which to offset the cross-field allowance.

Losses from abandoned fields
Detailed rules deal with the costs of field abandonment. Such costs are allowable for PRT if incurred for the removal or restoration of an asset or for obtaining an abandonment guarantee. Certain costs incurred in respect of defaults by a fellow participator are also allowable.

A participator can generally set off losses against profits of earlier periods, although any carryback will displace oil allowance and safeguard. Where repayments arise following a carryback, the amount of interest on tax repaid is restricted.

Where an abandoned taxable field has a residual loss (after carryback against earlier profits from that field) the excess may be set against profits from other fields. The losses which can be transferred are restricted to those arising from expenditure incurred on the field which is at the end of its life.

There are a number of anomalies and defects in the PRT legislation at September 2000. At this time a consultative process (in respect of defects in the fiscal legislation relating to abandonment) is underway between the industry and the Inland Revenue, with the potential for amendments to be introduced in the *Finance Bill 2001*. For further details on abandonment, see page 20.

Oil allowance
Oil allowance is a gross production relief which reduces the effective PRT rate, but which cannot be used to create a tax loss.

For *new* fields (*ie* where development consent was first given after 31 March 1982) the allowance represents the cash value of the equivalent of 500,000 metric tonnes per field per chargeable period. The aggregate allowance is 10 million tonnes, *ie* the allowance will normally last 10 years.

However 'new' onshore and Southern Basin fields (between latitudes 52° and 55°) have a reduced oil allowance of 125,000 metric tonnes per field per chargeable period (aggregate 2.5 million metric tonnes).

For other fields the allowance is equivalent to 250,000 tonnes per field per chargeable period (aggregate 5 million tonnes).

To the extent that oil allowance is not fully used in a period it can be carried forward. However, the limit per chargeable period remains the same but the allowance will now last for a longer duration. If the allowance is not used up it must be reconverted to an amount in metric tonnes of oil.

Safeguard
The safeguard rules provide that PRT payable for a chargeable period cannot exceed 80% of the amount by which the 'adjusted profit' for that period exceeds 15% of the 'accumulated capital expenditure' at the end of the period. The adjusted profit figure is the sum of assessable profit for PRT purposes with expenditure qualifying for uplift together with uplift and any non-field expenditure claimed added back. The accumulated capital expenditure is the total expenditure qualifying for uplift taken into account in previous periods.

Safeguard applies during the period prior to payback, as defined for uplift purposes (although in most circumstances the company will not be paying PRT for this period) and for a further time equal to half that period.

Hence safeguard relief is a form of marginal relief for less profitable fields. It is, however, not a deduction but is calculated completely separately. Where the safeguard figure calculated is less than the amount of PRT calculated in the normal way, the safeguard figure becomes the amount of PRT payable for those periods falling within the safeguard period.

Payment of PRT
Payments comprise:
- Six instalments for each chargeable period based on prior period liabilities.
- Payment on account.
- Payments due under assessments.

Instalments are payable monthly, commencing two months after the beginning of the chargeable period to which they relate. Each instalment is calculated as one-eighth of the total payment for the previous chargeable period.

Companies are required to self-assess their own PRT liability. The provisional PRT liability is computed on a special return *PRT 6*. The computation is broadly the same as that used for assessment purposes, except that expenditure may be deducted on a 'claimed' basis, whether or not allowed by the Inland Revenue. Payment is due two months after the end of the chargeable period.

When PRT is finally assessed by the Inland Revenue, any balance will either become payable or repayable.

Figure 4: Sample PRT computation
The following computation illustrates the typical sources of income and expenditure of a participator.

	£	£
Gross profit/(loss)		x
Tariff receipts (less allowance)		x
Asset disposal receipts		x
Royalty and licence debit/(credit)		x
Provisional expenditure allowance, net of reversal	x	
Share of joint field expenditure	x	
Participator's own field expenditure	x	
Uplift	x	
Exploration and appraisal expenditure	x	
Cross-field allowance	x	
Research expenditure	x	
Losses from abandoned fields	x	
Total		**(x)**
Assessable profit/(allowable loss)		x
Loss relief		(x)
Oil allowance		(x)
Taxable profit/(loss)		**x**
Tax at 50% (subject to safeguard)		**x**

Corporation tax

Introduction
UK oil companies pay corporation tax (CT) under the self assessment provisions in the same way as other UK companies. They are also subject to the following key points:

- Oil extraction activities are treated as a separate trade (the ring-fence rules).
- Where PRT rules require a disposal of oil to be treated as being made at market value, the same value is used for CT purposes. These valuation rules apply equally to oil won from non-PRT fields.
- Ring-fence restrictions may apply in some cases regarding relief for interest.
- PRT is deductible in computing income for CT purposes.
- Special rules apply to the commencement of trading and relief for expenditure.

Rates
The rate of corporation tax from 1 April 1999 is 30%. Certain small companies with low profits may benefit from the small companies' rate of 20% or with very small profits even the 10% starting rate.

The ring-fence
Under the ring-fence rules, UK oil extraction activities (including royalty interest and certain tariff receipts) are treated as a separate trade even if they form only part of a company's trade. These rules are aimed at preventing the dilution of the tax take from the exploitation of UK oil and gas reserves. They permit set-off of losses within the ring-fence against non ring-fence income, but prevent losses outside the ring-fence from relieving ring-fence profits. Non-UK activities, (*eg* oil exploration overseas) are outside the ring-fence.

Corporation tax is an entity tax and thus there are no field by field restrictions, nor any distinction between PRT taxable and non-taxable fields.

Subject to the ring-fence restrictions, in general CT losses may be carried forward and offset against future trading profits of that trade or set off against other profits of the accounting period in which the loss arises.

In addition (subject to the ring-fence), losses can be carried back to the previous year and set off against the total profits for that year.

Certain capital gains also fall within the ring-fence rules. Gains on the disposal of field interests and assets can only be reduced by losses or group relief, which derive from ring-fence assets or activities. Disposals of shares in UK oil companies are not treated as ring-fence capital

gains. Note that non-UK residents are taxed on disposals of shares in unquoted UK oil companies (see page 22).

Figure 5: Outline ring-fence CT computation

	£	£
Profit/(loss) per accounts		x
Add:		
Pricing adjustments (if any)	x	
Book depreciation	x	
Disallowable expenditure (*eg* entertaining)	x	
Capital costs expensed	x	
Provisions for future costs	x	
Payable under loan relationships	x	
		x
Less:		
PRT and royalty	x	
Capital gains	x	
Interest received	x	
Capital allowances	x	
Receivable under loan relationships	x	
Trading losses of other periods	x	
		(x)
Taxable ring-fence trading income		x
Capital gains		x
Interest		(x)
Taxable profits (subject to group relief)		**x**

Expenditure relief and allowances

General and administrative costs of a revenue nature are usually deducted in full as incurred. This was the case for intangible drilling costs prior to 26 November 1996. These costs are now relieved under the mineral extraction allowances (MEA) code on a 25% reducing balance basis.

A number of annual tax allowances are also available for qualifying expenditure at various stages in the life cycle of a field as follows:

- Plant and machinery writing-down allowances at 25% on a reducing balance basis. From 26 November 1996 'long life assets' (which when new can reasonably be expected to have a working life of greater than 25 years) qualify for a reduced allowance of 6%. This is the allowance for most tangible plant and equipment.
- Scientific research allowance (SRA) of 100%.
- Industrial buildings allowance (IBA) of 4% on a straight-line basis.
- MEA at 10% or 25% on a reducing balance basis.
- For fields abandoned after 30 June 1991, a 100% abandonment allowance (AA).

Scientific research allowances

By agreement with the Inland Revenue the costs of seismic work and exploration in the UK or on the UKCS are regarded as qualifying for SRA, provided they are incurred before the decision to proceed with

the commercial development of a field. Generally this point is established as the date on which the field receives development consent.

Scientific research expenditure (related to the company's trade) qualifies for full 100% write-off as incurred, although there is provision for clawback of SRAs on the disposal of an asset representing scientific research.

Mineral extraction allowance
Expenditure on 'mineral exploration and access' and certain costs in acquiring 'mineral assets' may be relieved by way of MEAs.

The normal rate of allowance is 25%. A reduced rate of 10% applies to expenditure on mineral assets (such as original licence premium) and to certain pre-trading expenditure on mineral exploration and access.

Abortive exploration expenditure (including that incurred in the six years before commencement of trade) may be written off in full when work ceases at a particular source. However, as this will normally have obtained SRA this situation is rarely encountered for UK oil and gas companies. Second-hand costs generally retain the same character (and therefore rate of allowance) as the original expenditure.

Abandonment allowance
The abandonment issue is one of real concern to the industry, as some of the sector's major fields near the end of their economic life. To date only a number of small fields have been abandoned and most of these have used floating production facilities or been linked by a sub-sea tieback to another field. Where existing infrastructure has been removed, the facilities have been on Southern Basin gas fields. These installations have been removed by a simple crane lift operation. It is anticipated that the Phillips operated Maureen platform will be the first major installation to be removed.

There is currently much discussion between the industry and the Inland Revenue in respect of the rules relating to abandonment. This section gives a brief overview of the corporation tax position for abandonment at the time of writing, although it is expected that amendments to the legislation (providing clarification in a number of areas and ameliorating certain defects) may be subsequently introduced.

Currently, a 100% deduction under capital allowances legislation against profits of a ring-fence trade is available on election. This must be made within two years of the end of the relevant accounting period for expenditure incurred in respect of abandoning an oil field.

For the expenditure to qualify it must relate to the demolition of oil installations or to the costs associated with preparing these facilities for reuse. The expenditure must be of such a nature as to qualify under the plant and machinery capital allowance rules and must relate to an abandonment programme within Part I of the *Petroleum Act 1987*. The

Inland Revenue's perceived strict interpretation of what expenditure qualifies for this allowance is an area currently under discussion.

Any loss resulting from abandonment can be set off against profits of the trade in the preceding three years. Many in the industry currently see this three-year period as inadequate, particularly since fields tend to be less profitable towards the end of their life. The provisions relating to this carryback of losses are currently being reviewed by the Inland Revenue.

Where a company has discontinued its ring-fence activities (*ie* ceased oil or gas production) and incurs abandonment costs within three years of the cessation, the company can claim a 100% capital allowance in respect of its final trading period. This will enable the company to receive a 100% balancing allowance for the final period of the company's trade.

The three-year time limit is seen by the industry as inequitable, particularly if the field has a common transport or terminal facility, in which case abandonment cannot proceed until the last user field ceases production. The procedure for the relief given to post-cessation of trade abandonment expenditure has been highlighted as an area requiring change and it is likely that the legislation will be amended, with either an extension to the three-year limit or the introduction of tax relief for 'buy out' payments.

Figure 6: Availability of key corporation tax allowances for capital costs

	Phase	Nature of costs	Tax allowance
1.	Concession acquisition	Geological and geophysical surveys	Scientific research
		Cost of licence	Mineral extraction
2.	Exploration	Drilling costs	Scientific research
3.	Appraisal	Drilling and associated costs	Scientific research
4.	Development	Development wells	Revenue expense/ mineral extraction
		Production facilities including platforms	Plant and machinery
		Pipelines and onshore facilities	Plant and machinery
5.	Production	Additional facilities	Plant and machinery
6.	Abandonment	Demolition of production facilities	Plant and machinery

Commencement of trade

The date of commencement of trade is an important date for companies calculating their corporation tax liability in the UK.

By agreement with the Inland Revenue a company's ring fence trade starts when a decision is made to develop its first oil field for

commercial production, generally the date of development consent.

Revenue expenditure incurred in the period within seven years prior to the commencement of trade then qualifies for CT relief. Expenditure qualifying for capital allowances incurred prior to the commencement of trade similarly triggers capital allowances. All such expenditure is treated as if it was incurred on the date of commencement of trade.

Currently non-trading income (typically interest income) is taxed as it arises without any offset of pre-trading expenditure.

Taxation aspects of acquiring North Sea assets

Introduction
Transactions involving North Sea assets are complicated, with multiple legal, commercial and taxation issues to resolve. Clearly any acquisition should be structured in a tax efficient manner with both the vendor and purchaser's requirements taken into account to maximise overall value. In particular structuring will play a key role in minimising tax leakage and value destruction from a transaction, for example by enabling a tax efficient break up bid or by providing synergies with existing tax attributes.

Deal structure: share v. asset purchase
There are a number of factors to be considered when deciding whether a transaction should take the form of a straight sale of assets, or a sale of shares in the company owning the assets. As well as tax there will be important legal issues, such as consideration of change of control, and pre-emption or other transfer related provisions in the Joint operating agreement (JOA).

The key tax considerations for both the vendor and the purchaser are highlighted below.

Share purchase
For a share acquisition, within the company transferred there are unlikely to be any internal PRT or CT consequences, as long as the trade continues. Any gain in the value of the shares since acquisition, arising on the disposal, will be chargeable to tax for the vendor. The gain will be chargeable where the vendor is UK resident and unusually will also be taxable in the hands of non-UK residents. The charge for non-UK residents arises as a result of specific provisions within the UK legislation in respect of disposals of UKCS assets or unquoted shares deriving the majority of their value from UKCS assets.

Any gain on the disposal of shares is not within the ring fence and additionally cannot be deferred under the rollover relief provisions.

Tax relief for costs of acquisition – asset purchase
Compared to a share transfer, the position for an asset sale is rather more complicated. For an asset transfer a 'just and reasonable' apportionment of consideration between the individual assets transferred is necessary. Consideration must be apportioned between:

Tangible field assets, which qualified for capital allowances in the hands of the vendor
The purchaser will receive capital allowances for this consideration, up to a maximum of the vendor's original expenditure on the assets. The purchaser will not receive allowances for any consideration above the original cost of the asset to the vendor, although this amount will be available to contribute towards the purchaser's capital gains basis in the asset.

The vendor will be required to bring into its capital allowances calculations the disposal proceeds, up to the original cost of the assets. If the proceeds are greater than the tax written down value (TWDV) of the assets at the date of the transaction, this surplus will be taxable. If the proceeds are less than the TWDV the vendor will receive a balancing tax allowance for this deficit. Any premium paid above the original cost of the assets will be chargeable to UK tax as a capital gain.

Assets which have qualified for MEAs in the hands of the vendor (eg intangible drilling costs)
As for consideration allocated to tangible fixed assets, the purchaser will receive allowances for the consideration up to a maximum of the vendor's original expenditure. Again the vendor will be subject to either a balancing charge or allowance in respect of this consideration, depending upon the asset's TWDV.

Assets which have qualified for SRAs in the hands of the vendor (exploration costs)
The purchaser will receive allowances for the consideration attributed to this asset under the MEA code, up to a maximum of the vendor's original expenditure. For the vendor the amount allocated to this asset will be clawed back as a taxable trading receipt, to a maximum of the original SRA.

Any further consideration not allocated to the above will not be tax deductible for the purchaser (however this consideration would contribute towards the purchaser's capital gains basis in the asset). For the vendor this amount would be taxable as a chargeable gain, subject to rollover relief.

Transfer of assets – PRT considerations
The transfer of a taxable field generally falls within the scope of *Schedule 17 FA 1980 (Schedule 17)*. The *Schedule 17* rules provide that (on transfer of a determined field) the transferee essentially assumes the PRT position of the transferor. All such transfers of licence interests (including those between unrelated parties) are covered, except Illustrative Agreements (IAs) and re-determinations under unitisation agreements.

Under these *Schedule 17* provisions the vendor does not bring into the PRT charge the consideration in respect of the disposal. Similarly the acquirer does not receive any relief in respect of this consideration.

The administrative arrangements in respect of PRT on the transfer of a field interest are extremely complex, since they interact with most sections of the PRT legislation. In practice, the Oil Taxation Office (OTO) assists in obtaining a fair and reasonable result.

Stamp duty

The sale of assets will be subject to stamp duty at 4% of the asset value, payable by the purchaser. The sale of shares is subject to UK stamp duty at a rate of 0.5%, again payable by the purchaser.

As at September 2000 it was still possible to defer the stamp duty cost for both a share or asset deal, by executing and retaining the documentation offshore. However if the documents are required onshore, the deferred tax will become due and interest will accrue from the date that the documents were executed. In addition there is a further risk that future anti-avoidance legislation could be subsequently introduced in this respect.

Financing

Strict rules apply restricting the deductibility of interest costs in respect of debt finance for UKCS investments. In addition to general transfer pricing rules, concerning the arm's length level of debt and rate of interest on related party loans, specific ring-fence restrictions apply which can limit relief for interest on both related and third party loans unless specific conditions are met. Specifically debt must be used to meet, or allocated to meet, expenditure incurred by the company in carrying on oil extraction activities or acquiring oil rights. A consequence of this is that no relief is given in respect of debt financing for a share acquisition.

Financial reporting

Introduction
The unique nature of the upstream oil and gas industry has historically resulted in the development of a variety of financial reporting and accounting practices, notwithstanding UK accounting standards and legislation. In order to develop specifically tailored guidance for the UK industry, the Oil Industry Accounting Committee (OIAC) was established in 1984.

Having been authorised by the Accounting Standards Board (ASB) and its predecessor body, the OIAC developed a number of statements of recommended practice (SORPs) and guidance notes to assist preparers of UK financial statements. Due to recent developments in general accounting practice, including the ASB's issuance of several new Financial Reporting Standards (FRSs), the OIAC recently rationalised its previous pronouncements into a combined SORP, issued in January 2000. Some of the matters addressed in this SORP are summarised below.

Commercial reserves
Depreciation and other accounting computations are performed with reference to 'commercial reserves'. In the US, commercial reserves are taken to be proven reserves only, which is appropriate for onshore activity but less appropriate for deep water activity. In the UK however, commercial reserves may, at a company's option, and based on their portfolio of interests, be taken as either:
- proven and probable oil and gas reserves; or
- proven developed and undeveloped oil and gas reserves

Pre-production costs
Pre-production expenditure may be accounted for in one of two ways. Under successful efforts accounting, whilst all expenditure is initially capitalised, only costs that relate directly to the discovery and development of commercial reserves remain capitalised, with other costs being written off to the profit and loss account. The costs are accumulated in field cost centres.

Companies adopting full cost accounting capitalise all pre-production expenditure in a cost pool, and these costs will remain capitalised irrespective of whether they result in the discovery of commercial reserves, as long as there are commercial reserves associated with the pool. The pools generally relate to an area no smaller than a country, yet are restricted to a geographical area that shares a significant degree of common characteristics.

The decision on which method to adopt depends on whether a company views its exploration activities as separate efforts to locate reserves (successful efforts), or as part of a larger effort in a defined area (full cost).

Decommissioning
A decommissioning provision is recognised progressively as facilities are installed, and is measured as the present value of the expected expenditure required to remove the installations, and rectify damage to the environment. The provision increases as the discounting to arrive at the present value unwinds. On initial recognition of the provision, the related debit entry is recorded to the field or pool cost centre included in fixed assets. The effect of subsequent changes in estimates is also recorded to the field or pool cost centre.

This methodology represents a significant change in practice following the issue of *FRS 12*. Previously, companies would build up a decommissioning provision over time, on a unit of production basis, in accordance with *SORP 3* (now withdrawn).

Ceiling tests
The net book value of expenditure accumulated in a field or pool cost centre is assessed for impairment using a ceiling test. This test determines whether the net book value (less any provisions for decommissioning or revenue related taxes) is recoverable from the present value of the expected future net pre-tax revenue from oil and gas reserves.

An identified deficit is charged to the profit and loss account as additional depreciation, but is however reversed in future periods to the extent that the cause of impairment reverses. The requirement to 'write-back' previous impairments was introduced by *FRS 11*, and has the potential to affect materially the reported earnings of upstream oil and gas companies, given the recent volatility in the oil price.

Depreciation
The depreciation of cost pools for full cost companies and field cost centres for successful efforts companies is essentially the same.

Depreciation is calculated using the ratio of oil and gas production in the period to the estimated quantity of commercial reserves at the end of the period plus the production for the period. This ratio is applied to the opening net book value of capitalised costs plus estimated development costs required to access all commercial reserves.

Production activities
Accounting for production activities is relatively straightforward. Turnover will generally include the actual amounts invoiced from the sale of the company's own share of oil and gas production and related services, exclusive of indirect taxes and excise duties. The treatment of royalties is dependent on the nature of the arrangement.

Where the royalty holder has a direct interest in underlying production, royalties should be excluded from turnover and cost of sales. In other circumstances, including in the absence of contractual guidance, the gross amounts should be recorded. The SORP recommends that any overlift or underlift *ie* the difference between the company's share of production and actual sales made for the period, be recorded against cost of sales at market value.

Joint ventures

The upstream oil and gas industry is characterised by the existence of joint ventures, largely due to the desire to share the often substantial risks of exploration and exploitation. The nature of the agreement will determine the appropriate accounting treatment.

Typical arrangements in the UK are such that each participant generally shares proportionately in the risks, costs and rewards and therefore accounts for its proportionate share of the costs, revenues, assets and liabilities of the joint arrangement. Other arrangements found outside the UK, commonly known as 'production sharing agreements', or 'concessions' are substantially different from that described above, and may be accounted for according to the basis on which the risks, costs and rewards are shared.

For further information

Arthur Andersen has a representative on the Oil Industry Accounting Committee (OIAC), and has been integrally involved in the establishment and development of OIAC. The above represents only a brief summary of selected topics in the combined SORP. Should you wish to obtain a copy of the SORP, or should you have any queries in relation to accounting and reporting for upstream oil and gas companies, we should be delighted to assist you. Please see contact details on page 29.

Arthur Andersen upstream oil and gas tax series

This guide is part of our international upstream oil and gas tax series, developed to provide outline, practical tax advice on some of the current areas of interest in upstream development worldwide, including the Caspian states, Russia and Iran. Further guides are planned for other emerging key locations, including the Middle East. Our *International oil and gas contacts directory* provides direct access to our upstream specialists anywhere in the world.

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- Azerbaijan oil and gas tax guide (May 2000)
- Iran oil and gas tax guide (March 2000)
- Kazakhstan oil and gas tax guide (October 2000)
- Turkmenistan oil and gas tax guide (March 2000)
- Russian oil and gas tax guide (October 2000)
- Arthur Andersen international oil and gas contacts directory 2000 (May 2000)

Contacts

For specific advice on upstream operations in the UK and UKCS contact:

Nicholas Woolf (Senior Tax Partner)
+44 20 7438 3756
nicholas.woolf@uk.arthurandersen.com

Gerard Anderson (Tax Partner)
+44 20 7438 3000
gerard.anderson@uk.arthurandersen.com

Julian Small (Tax Partner)
+44 20 7438 3062
julian.small@uk.arthurandersen.com

Carl Hughes (Assurance and Business Advisory Partner)
+44 20 7438 3253
carl.d.hughes@uk.arthurandersen.com

Kenneth McKellar (Managing Director, Petroleum Services)
+44 20 438 2572
kenneth.mckellar@uk.arthurandersen.com

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